

Evaluating Overhead Line Reclosing Sequences Based on Transformer Through-Fault Exposure

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Evaluating Overhead Line Reclosing Sequences Based on Transformer Through-Fault Exposure

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Abstract—Overhead line reclosing schemes are commonly used to minimize outage durations and maximize reliability on distribution feeders. While reclosing has shown reliability improvements (especially during temporary faults), reclosing into faults to test line segments subjects upstream power transformer windings to mechanical damage due to through-fault exposure. This paper demonstrates using the transformer through-fault capability curves of IEEE C57.109 to evaluate the through-fault damage of various reclosing sequences on an example distribution transformer.

Reclosing sequences evaluated include fuse-saving schemes, trip-saving schemes, overcurrent curve enhancements to traditional schemes, and hybrid schemes using high-speed wireless fault sensors. These sequences are evaluated for both temporary and permanent fault conditions. The coordination of multiple reclosers and sectionalizers in series on a distribution feeder is also considered in the sequences that are evaluated.

The method described in this paper provides distribution owners and operators with a tool to consider the reliability benefits of reclosing versus the loss of life of power transformers. Readers can apply their own distributions of fault currents, locations, durations, and frequencies to this method and quantify the benefits of enhancements to traditional reclosing schemes.

I. INTRODUCTION

When coordinating many radial distribution feeders, distribution engineers frequently develop and apply a standard overcurrent coordination scheme and reclosing scheme to all feeders based on typical feeder conductor sizes, feeder lengths, impedances, loads, available fault currents, and fuse sizes. In this paper, two different distribution transformer banks fed from the same transmission system are analyzed. The overcurrent and reclosing schemes applied to feeders using feeder circuit breakers and multiple reclosers are considered in terms of through-fault damage to the distribution transformer banks. The same overcurrent coordination and reclosing schemes are applied to 13 kV feeders on both transformers. Fig. 1 shows a simplified one-line diagram with the distribution transformer on the left and the feeder on the right.

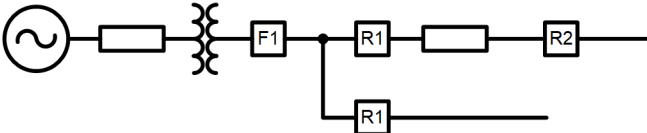


Fig. 1. Simplified System One-Line Diagram

A. Example Feeder

The example feeder includes multiple reclosers to achieve sensitivity and selectivity for most fault conditions on the feeder. An end-of-line recloser is required for parts of the feeder where the minimum fault current levels are lower than the

feeder breaker minimum sensitivity. Midpoint reclosers are applied to minimize the number of customers impacted by permanent faults. Reclosing is applied to the feeder breaker and reclosers to automatically restore power to customers following temporary faults. Overcurrent and reclosing settings for Feeder Breaker F1, Recloser R1, and Recloser R2 are described in Table I.

TABLE I
FEEDER COORDINATION AND RECLOSING DATA

	F1	R1	R2
Minimum Trip (A)	600	600	400
Maximum Fault (A)	Same as distribution substation bus	Same as distribution substation bus	800
Fast Curve	None	R	A
Delay Curve	U3 (TD = 5)	C	C
Trips to Lockout	3	3	3
Open Interval 1 (s)	1	1	1
Open Interval 2 (s)	15	15	15
Clearing Time (s)	0.05	0.05	0.05

1) Feeder Breaker F1

F1 represents a feeder breaker at the substation that is set to protect the main feeder conductors leaving the substation. The settings for the feeder breaker can be generated by the distribution engineer coordinating downstream feeder protection elements or can be generated by the substation engineer coordinating with upstream transformer protection and the transformer damage curve; both the downstream feeder protection elements and upstream transformer damage curve need to be considered when setting F1. The speed and sensitivity of the F1 phase overcurrent protection is limited by the maximum load that can be carried on the feeder and the impedance to the first downstream recloser. For proper coordination, all overcurrent elements that respond to faults beyond downstream reclosers need to be slower than the downstream reclosers. If the first downstream recloser is relatively close to the substation, an instantaneous element cannot be set for F1. Since there is practically no impedance between the distribution transformer and F1, the maximum fault current seen by F1 is equal to the maximum through-fault current for the transformer.

2) Midpoint Recloser R1

R1 represents midpoint reclosers on the feeders relatively close to the substation. This may be a result of the main feeder

splitting and serving customers in two different directions or very high customer density close to the substation. Very little impedance is assumed between the substation and R1, so the maximum fault current seen by R1 is the same as the maximum through-fault current for the distribution transformer bank. R1 overcurrent elements that may respond to faults beyond downstream reclosers and fuses must be slower than the downstream reclosers and fuses for proper coordination.

3) End-of-Line Recloser R2

R2 represents a recloser near the end of the feeder. Faults further from the substation will have lower fault currents as the impedance between the fault location and the substation increases. For longer feeders, the fault currents at the end of the feeder may be less than the minimum phase pickup current levels associated with F1 and R1. For this example, assume that the maximum available fault current at R2 is 800 A and the minimum phase fault current at the end of the line is greater than 400 A. The maximum load seen by R2 is significantly less than F1 and R1, allowing the minimum phase pickup to be less than F1 and R1. R2 overcurrent elements must be slower than the slowest downstream fuses. The slowest fuses on the feeder are assumed to be 100T. Overcurrent curves for F1, R1, and R2 are shown in Fig. 2.

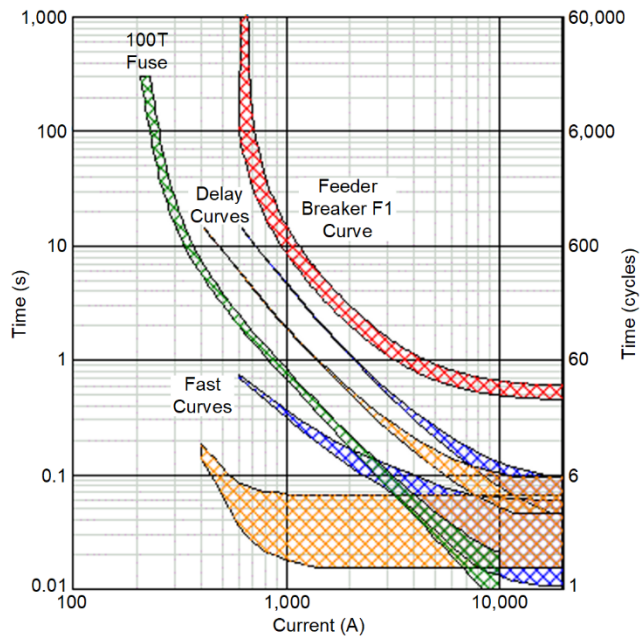


Fig. 2. Overcurrent Curves for F1 (red), R1 (blue), R2 (orange), and 100T Fuse (green)

B. Example Distribution Transformer Banks

For the example feeder configuration and a common transmission source, two different distribution transformer banks with different capacities and impedances are referenced and analyzed in this paper. The two distribution transformer banks represent transformer banks of various sizes used by utilities for urban and industrial locations with higher load density versus rural areas with lower load density. In higher load density areas, four or more feeders can be connected to each transformer bank, but only one or two feeders are commonly connected to each transformer bank in areas with

lower load densities. Damage curves for transformers are commonly expressed in per unit (pu) of the full load rating of each transformer. The capacities, number of feeders, maximum through-fault current, and cooling parameters associated with IEEE C57.91 for each transformer are listed in Table II.

TABLE II
TRANSFORMER DATA

	Transformer A	Transformer B
Top MVA Rating (MVA)	30	10
Feeders	4	2
Impedance (%)	5	6
I Nominal (A)	1,400	450
Maximum Through-Fault Current (A)	14,000 (10.0 pu)	5,850 (13.0 pu)
Cooling Method	ONAF (Oil Natural Air Forced)	
Average Winding Rise Over Ambient at Rated Load ($^{\circ}$ C)	65	
$\Delta\Theta_{TO,R}$ (top oil rise over ambient at rated load in $^{\circ}$ C)	50	
$\Delta\Theta_{H,R}$ (hot spot rise over top oil at rated load in $^{\circ}$ C)	30	
$\tau_{TO,R}$ (oil time constant in hrs)	2.0	
R (ratio of load loss at rated load to low load loss)	4.5	
n (top oil exponent)	0.9	
m (hot spot exponent)	0.8	
τ_H (winding time constant in hrs)	0.08	
B (constant)	15,000	
Insulation Life (hrs)	180,000	

C. Transformer Damage Curves

These two transformers only differ in capacity and impedance. Because the cooling parameters are the same and damage curves are commonly expressed in pu of transformer maximum rated load current, damage curves associated with both transformers are plotted on a single graph shown in Fig. 3.

Transformer damage curves consist of two parts: a thermal damage curve associated with the winding insulation and a mechanical damage curve associated with deformation of the winding conductors [1]. The two mechanical damage curves shown in Fig. 3 are associated with transformer impedances of 5 and 6 percent. These two thermal damage curves are derived using equations from IEEE C57.91 and assume ambient temperatures of 30 $^{\circ}$ C and 40 $^{\circ}$ C.

Thermal damage curves can be derived using the short-time capability of the transformer, assuming that the transformer is fully loaded and has a maximum hot spot temperature of 180 $^{\circ}$ C [2]. The thermal damage curve is commonly drawn as a single curve but is impacted by transformer loading and ambient temperature. The maximum expected transformer loading and maximum expected ambient temperature is used to determine the worst-case impact to transformer insulation.

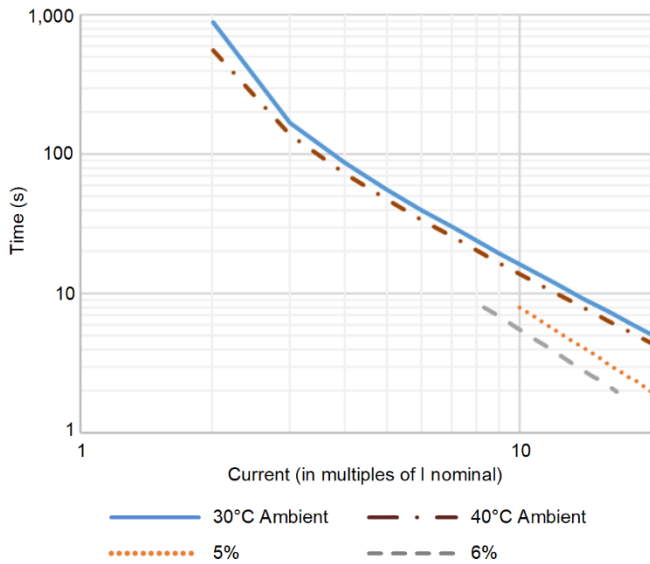


Fig. 3. Transformer Damage Curves

Thermal damage to the insulation results in accelerated aging of insulation and reduced life expectancy. While the actual fault durations are short, the cooling time constants can result in many hours of lost transformer life due to elevated hot spot temperature and accelerated aging. Fig. 4 shows the expected transformer hot spot temperature as it cools from 180°C back to normal conditions. In the 6 hours following the fault, the elevated temperatures caused more than 18 hours of lost life and resulted in a loss of more than 12 hours from the expected lifespan of the transformer insulation.

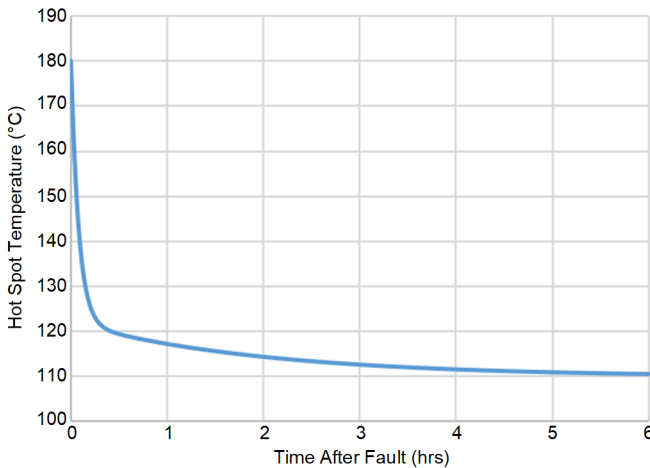


Fig. 4. Hot Spot Temperature From 180°C

Time constants associated with the transformer thermal model are generally expressed in hours. When thermal time constants are compared to reclosing cycles that are in seconds or minutes, the cooling during reclose open intervals has negligible effects on the overall temperature of the transformer. Fig. 5 represents transformer hot spot temperature during a reclose cycle with an ambient temperature of 40°C, 10 pu fault currents, three trips with approximately 5-second operation times, two recloses, and open intervals of 1 second and 15 seconds. The combined impact of the 16 seconds of cooling during the open intervals results in a less than 2°C change in hot

spot temperature. The 2°C cooling is significantly less than the 60°C in temperature rise during the reclose cycle. Therefore, when the thermal impact of a fault on a transformer is determined, the accumulated fault duration of all trips for the entire reclose cycle must be considered. Cooling effects during open intervals can be ignored.

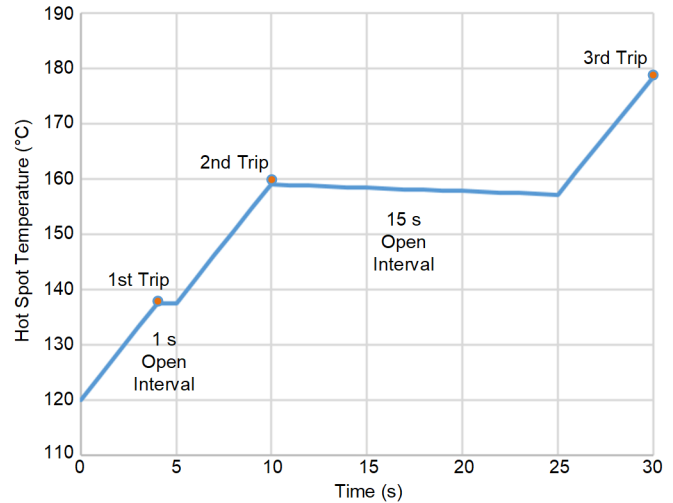


Fig. 5. Transformer Hot Spot Temperature for Three 5-Second Trips

Following the clearing of the fault and the locking out of the reclosing elements, the transformer oil and winding temperatures should eventually return to normal ranges without any detrimental effects, except for the loss of life of the insulation.

Unlike thermal damage, the times associated with mechanical damage curves are based on the accumulated exposure to the fault current over the life of the transformer and the bending of the windings due to forces generated between turns in the winding during fault conditions [1]. The mechanical damage curves are dependent on transformer impedance and derived assuming a maximum of 2 seconds of exposure to the maximum possible through-fault current through the transformer when the transformer is connected to a strong source or infinite bus. Mechanical damage is only considered for faults greater than 50 percent of the maximum possible through-fault current through the transformer resulting in mechanical damage curves for 5- and 6-percent transformer impedances, starting at 10.0 pu current and 8.3 pu current, respectively. Since mechanical damage accumulates over the life of the transformer and damage times associated with mechanical damage are shorter than the thermal damage times, the thermal damage curve is generally ignored for currents associated with the mechanical damage curve. For high fault current magnitudes, significant mechanical damage is expected long before a transformer hot spot temperature of 180°C is reached.

II. END-OF-LINE RECLOSER R2

When the transformer damage curves are considered in relation to the maximum available fault current associated with R2, the maximum available fault currents at R2 are only 0.57 pu and 1.78 pu for Transformer A and Transformer B,

respectively. The transformer damage curves start at 2.0 pu; therefore, faults beyond Recloser R2 and the reclosing settings of R2 do not need to be considered for transformer damage. The operating times of end-of-line reclosers, fuses, and inrush currents of connected loads impact overcurrent coordination and the operating times of midpoint reclosers and feeder breakers. This results in end-of-line reclosers like R2 having an indirect impact on through-fault damage to distribution transformer banks.

III. MIDPOINT RECLOSER R1

A traditional trip-saving scheme or fuse-saving scheme can be applied to Recloser R1. Trip-saving schemes use delay curves for all trips, but fuse-saving schemes use one or more fast curve trips before tripping using the delay curve. Fuse-saving schemes in this paper use a single fast curve trip before switching to the delay curve trips. Fuse-saving schemes are intended to minimize fuse replacement for temporary faults beyond fused laterals.

A. Permanent Fault on Main Feeder

The first case to consider is a permanent fault on the main feeder just after R1. The maximum available fault current seen by R1 corresponds to 10.0 pu current on Transformer A and 13.0 pu current on Transformer B. Fast curve and delay curve clearing time for faults just beyond R1 depend on the actual fault current in primary amperes. Based on the per-unit fault current and the total fault duration seen by the transformers, Table III shows the fault times, hottest hot spot temperature, thermal loss of life, mechanical damage limit, and the number of faults before mechanical damage is plotted for both trip-saving and fuse-saving schemes.

TABLE III
MAIN FEEDER PERMANENT FAULT AT R1

	Transformer A		Transformer B	
Fault Current (A)	14,000 A		5,850 A	
Tripping Scheme	Trip Saving	Fuse Saving	Trip Saving	Fuse Saving
Fast Curve Clearing Time (s)	N/A	0.06	N/A	0.07
Delay Curve Clearing Time (s)	0.1		0.2	
Number of Trips	3	3	3	3
Total Fault Time (s)	0.3	0.26	0.6	0.47
Fault Current (pu)	10.0		13.0	
Hottest Hot Spot Temperature (°C)	111.32	111.14	114.07	113.19
Thermal Loss of Life (min)	2	1.6	6	4.6
Mechanical Damage Limit (s)	8		3.29	
Faults to Mechanical Damage	27	31	6	7

Depending on the transformer and available fault current, the fuse-saving scheme saves between 13 and 22 percent of the total fault time for a permanent fault on the main feeder. This corresponds to 20 to 23 percent savings in thermal loss of life and one to four more faults before the transformer mechanical damage limit is reached.

B. Temporary Fault on Main Feeder

If fuse-saving schemes reduce distribution transformer bank damage for permanent faults, the impact of fuse-saving schemes for temporary faults should be considered. Using the same available fault currents as the previous permanent fault on the main feeder, the total fault current times are calculated assuming that the fault cleared after the first trip. The impact of total fault current times and transformer damage are shown in Table IV.

TABLE IV
MAIN FEEDER TEMPORARY FAULT AT R1

	Transformer A		Transformer B	
Fault Current (A)	14,000		5,850	
Tripping Scheme	Trip Saving	Fuse Saving	Trip Saving	Fuse Saving
Fast Curve Clearing Time (s)	N/A	0.06	N/A	0.07
Delay Curve Clearing Time (s)	0.1		0.2	
Number of Trips	1	1	1	1
Total Fault Time (s)	0.1	0.06	0.2	0.07
Fault Current (pu)	10.0		13.0	
Hottest Hot Spot Temperature (°C)	110.44	110.26	111.36	110.47
Thermal Loss of Life (s)	36	22	115	40
Mechanical Damage Limit (s)	8		3.29	
Faults to Mechanical Damage	80	134	17	47

Compared to permanent faults, the fuse-saving scheme results in a greater reduction in transformer damage for temporary faults, including a 39 to 65 percent reduction in thermal loss of life per fault and 30 to 54 more temporary faults before the mechanical damage limit is reached.

C. Faults on Fused Laterals

All fused laterals beyond Recloser R1 are assumed to have 100T fuses or faster. The R1 fast curve coordinates with the 100T fuse for faults up to 2,000 A. With an open interval time of 1 second or less for the fuse-saving scheme, fuse cooling does not significantly affect the operating time of the 100T fuse [3]. Therefore, a permanent fault on a fused lateral results in similar transformer through-fault damage when a trip-saving or fuse-saving scheme is used, as shown in Table V. If the open interval time increases more than 1 second, the cooling factor for the fuse results in longer fuse clearing time after the first reclose for the fuse-saving scheme [3]. This results in a slightly

longer total fault duration and can increase the transformer through-fault damage associated with the fuse-saving scheme.

For a temporary fault, using the R1 fast curve with a fuse-saving scheme to clear the fault results in a shorter fault clearing time and fewer fuse replacements than using a trip-saving scheme. Table V shows the shorter total fault clearing time and a 34-percent reduction in transformer thermal loss of life compared to clearing the temporary fault with the fuse.

TABLE V
FAULT OF FUSED LATERAL

Tripping Scheme	Transformer B		
	Trip Saving	Permanent Fault, Fuse Saving	Temporary Fault, Fuse Saving
Fault Current (A)	2,000		
Fast Curve Clearing Time (s)	N/A	0.15	0.15
Delay Curve Clearing Time (s)	0.6		
Fuse Clearing Time (s)	0.23		N/A
Number of Trips	0	1	1
Total Fault Time (s)	0.23	0.23	0.15
Fault Current (pu)	4.44		
Hottest Hot Spot Temperature (°C)	110.25	110.25	110.17
Thermal Loss of Life (s)	19.0	18.9	12.3

D. Sequence Coordination

Another possible scenario to consider is moving R2 closer to R1 so that the maximum available fault current at R2 is approximately 3,000 A, just under the coordination limit between the R1 and R2 fast overcurrent curves. When trip-saving schemes are used, R1 is always slower than R2 and R2 clears a permanent fault just beyond R2 after three delay curve trips. With fuse-saving schemes, a permanent 3,000 A fault just beyond R2 can result in the unnecessary fast curve tripping of R1 based on the following sequence:

1. R2 trips on fast curve.
2. R2 recloses, and R1 trips on fast curve.
3. R1 recloses, and R2 trips on delay curve.
4. R2 recloses.
5. R2 trips and locks out on delay curve.

Enabling sequence coordination on R1 allows the recloser shot counter to advance when the fast curve on R1 begins to time. This keeps shot counters on R1 synchronized with R2 and results in R1 and R2 switching to the delay curve at the same time. This prevents R1 from tripping for faults beyond R2. The overall impact of these three reclosing schemes to the hottest hot spot temperature and thermal loss of life are shown in Table VI and Fig. 6.

TABLE VI
3,000 A FAULT AT R2

Tripping Scheme	Transformer B		
	Trip Saving	Fuse Saving	Fuse Saving With Sequence Coordination
Fault Current (A)	3,000		
R2 Fast Curve Clearing Time (s)	N/A	0.07	0.07
R2 Delay Curve Clearing Time (s)	0.24		
R1 Fast Curve Clearing Time (s)	N/A	0.13	N/A
Number of Trips	3	4	3
Total Fault Time (s)	0.72	0.68	0.55
Fault Current (pu)	6.67		
Hottest Hot Spot Temperature (°C) (See Fig. 6)	111.56	111.47	111.20
Thermal Loss of Life (s)	127	120	97

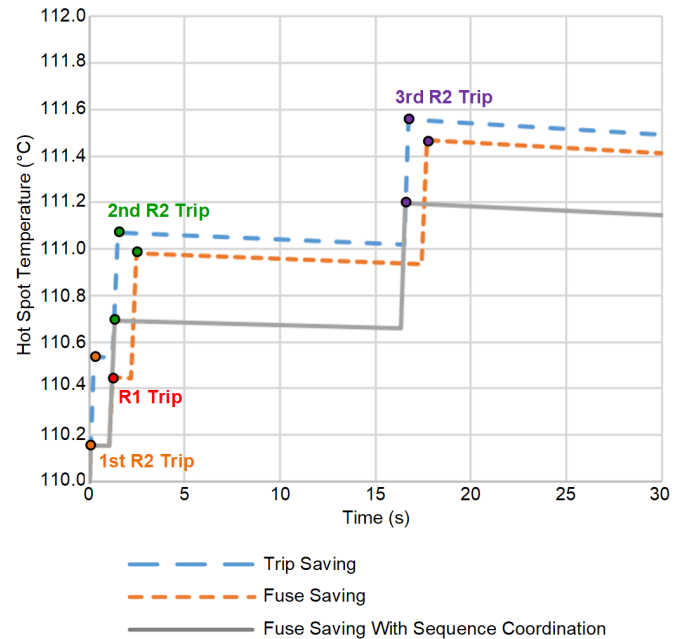


Fig. 6. Transformer Hot Spot Temperatures for 3,000 A Faults at R2

While a review of the thermal loss of life and hottest hot spot temperature shows fuse-saving schemes without sequence coordination result in less impact to transformer thermal loss of life compared to trip-saving schemes, this reduction in transformer damage must be weighed against the increased number of customers experiencing a temporary outage due to the operation of R1. Adding sequence coordination to a fuse-saving scheme further reduces transformer damage while eliminating the unnecessary operation of R1.

E. Reenabling Fast Curve Trip

Delay curve trips are required in any reclosing scheme to establish selectivity with downstream fuses and downstream reclosers. Once a recloser trips on a delay curve in a properly coordinated system, the fault is known to be within its zone of protection and not on a fused lateral or beyond a downstream recloser. Therefore, upon reclose after a delay curve trip, it is not necessary for the recloser to coordinate with downstream time-overcurrent devices [4].

Table VII shows the impact of reenabling the fast curve on the third trip for a permanent 3,000 A main feeder fault beyond R1. Inrush restraint or a modified minimum pickup should be used when picking up load with a fast curve; this may result in a slightly longer operating time than using the traditional fast curve. For simplicity, it is assumed that the inrush restraint fast curve has a similar operating time as the fast curve used in a fuse-saving scheme. With the shortened duration of the total fault current, reenabling the fast curve reduces transformer thermal loss of life by 15 to 18 percent compared to similar schemes with multiple delay curve operations in this application.

TABLE VII
PERMANENT 3,000 A MAIN FEEDER FAULT

	Trip Saving		Fuse Saving	
	Delay Curve	Fast Curve	Delay Curve	Fast Curve
Fault Current (A)	3,000			
Third Trip	Delay Curve	Fast Curve	Delay Curve	Fast Curve
Fast Curve Clearing Time (s)	N/A	0.13	0.13	0.13
Delay Curve Clearing Time (s)	0.24			
Number of Trips	3			
Total Fault Time (s)	0.72	0.61	0.61	0.50
Fault Current (pu)	6.67			
Hottest Hot Spot Temperature (°C)	111.56	111.31	111.32	111.08
Thermal Loss of Life (s)	127	107	107	88

F. Sectionalizers

Additional delay curve trips are commonly added beyond the three trips defined for F1, R1, and R2 to allow coordination with line sectionalizers. Line sectionalizers count the number of times an upstream device has interrupted a fault downstream of the line sectionalizer. After a predefined number of upstream recloser operations, line sectionalizers open to isolate downstream faults and allow the upstream recloser to successfully reclose. The additional delay curve trip for the upstream recloser can increase the total fault time applied to the transformer for all faults downstream of the recloser. As long as selectivity with fuses on laterals is established with a single delay curve operation, additional trips for coordination with sectionalizers can be fast trips with inrush restraint. This reduces the through-fault damage associated with the additional reclose attempts.

IV. FEEDER BREAKER F1

Fast curve trips are commonly implemented using instantaneous overcurrent elements on feeder breakers. In this application, R1 is close to the substation, resulting in the same available fault current at R1 and F1. Because the available fault currents are nearly the same, an instantaneous overcurrent element that is secure for faults beyond R1 cannot be set on F1. The lack of a fast curve or instantaneous element on F1 prevents the use of a fuse-saving scheme, which has already shown reductions in transformer through-fault impact when applied to R1. Methods that do not depend on fault current magnitude to establish selectivity with downstream overcurrent elements are necessary to reduce transformer through-fault damage. These can include wireless line sensor systems or high-speed peer-to-peer communications with downstream recloser controls.

A. Permanent Main Feeder Faults Between F1 and R1

Wireless protection sensor (WPS) systems can send fault information at protection speeds from remote locations (such as fuses and downstream reclosers) to feeder breakers in less than one power system cycle [5]. When applied with feeder circuit breakers rated to clear faults in under 50 milliseconds, WPS systems allow intelligent switching between trip-saving and fuse-saving schemes, with fault clearing times as low as 0.07 seconds.

The first example WPS system application requires the installation of sensors on downstream recloser R1. This allows relaying for F1 to distinguish between faults within its zone of protection before R1 and faults beyond R1. F1 can then use a fast curve or short-delay definite-time overcurrent element for a fuse-saving scheme and allow a first trip to clear faults on the main feeder or fused laterals in as low as 0.07 seconds. F1 must still switch to delay curve tripping to coordinate with fuses for faults on fused laterals but can switch back to a fast curve with inrush restraint for the third trip as in the scheme previously applied to R1.

Additional sensors can be installed to detect the presence of faults on fused laterals. Since selectivity is established without coordination of time-delayed overcurrent elements, through-fault damage to the transformer can be further reduced by delaying all feeder breaker trips that are only long enough to receive blocking signals from the sensors. Upon reclose, a modified pickup or inrush restraint can be applied to a fast overcurrent element to restrain for transformer inrush but still allow accelerated tripping instead of relying only on delay-curve tripping. Fig. 7 shows sensors applied to both laterals and a downstream recloser.

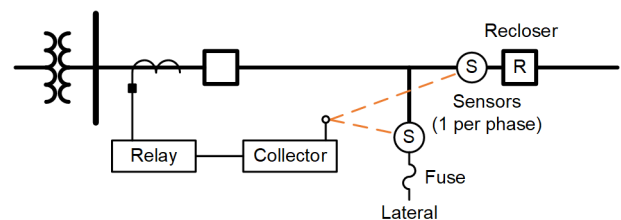


Fig. 7. Wireless Protection Sensors Applied to Recloser and Fused Lateral

Table VIII demonstrates the reduction of thermal loss of life and transformer mechanical damage when integrating a WPS system with F1. Using sensors only on the downstream recloser reduces the thermal loss of life by about 65 percent and doubles the number of faults before mechanical damage to the transformer. Adding sensors to both the downstream reclosers and fused laterals reduces thermal loss of life by 93 percent and increases the number of faults before mechanical damage by a factor of eight.

TABLE VIII
MAIN FEEDER PERMANENT FAULT AT F1

Transformer B			
Fault Current (A)	5,850		
WPS Sensor Locations	None	Downstream Reclosers	Downstream Reclosers and Fused Laterals
Fast Curve Clearing Time (s)	N/A	0.07	0.07
Delay Curve Clearing Time (s)	0.8		N/A
Fast Curve Trips	0	2	3
Delay Curve Trips	3	1	0
Total Fault Time (s)	2.4	0.94	0.21
Fault Current (pu)	13.0		
Hottest Hot Spot Temperature (°C)	126	116	111
Thermal Loss of Life (min)	27	9.5	2
Mechanical Damage Limit (s)	3.29		
Faults to Mechanical Damage	2	4	16

B. Faults on Underground Sections

Line sensors for WPS systems can be used to further reduce transformer through-fault damage by allowing the feeder breaker relay to identify faults on underground sections of the main feeder. Faults on underground sections are almost always permanent faults. Once the relaying for F1 has located the fault on an underground section using the WPS system, all reclose attempts can be cancelled.

The most common application for underground cables is associated with underground takeoffs from the feeder breaker inside the substation to just beyond the substation. For faults on the underground takeoff from the substation, no fuses exist between the F1 and the fault. A WPS system can be installed where the main feeder transitions from underground to overhead, as shown in Fig. 8, with reclosing enabled only for faults beyond the underground takeoff. This allows faults on underground takeoffs to be cleared with a single fast curve trip. Using the WPS system to enable fast trip and cancel recloses reduces thermal loss of life by more than 97 percent and allows Transformer B to sustain 285 times more faults before damage (for faults on the underground takeoff), as shown in Table IX.

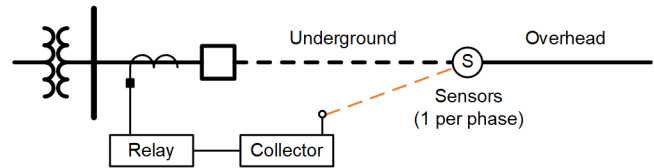


Fig. 8. Wireless Protection Sensors Applied at Underground Overhead Transitions

TABLE IX
PERMANENT FAULT ON UNDERGROUND TAKEOFF

Transformer B		
Fault Current (A)	5,850	
WPS Sensor Locations	None	Underground Overhead Transition
Fast Curve Clearing Time (s)	N/A	0.07
Delay Curve Clearing Time (s)	0.8	N/A
Fast Curve Trips	0	1
Delay Fast Curve Trips	3	0
Total Fault Time (s)	2.4	0.07
Fault Current (pu)	13.0	
Hottest Hot Spot Temperature (°C)	126	110.5
Thermal Loss of Life (min)	27	0.67
Mechanical Damage Limit (s)	3.29	
Faults to Mechanical Damage	2	571

V. CONCLUSION

Application of technologies like WPS and reclosing scheme modifications can result in significant reductions in transformer through-fault damage. Because of differences in fault current magnitudes, improvements in reclosing schemes closer to the substation make a more significant impact in reducing transformer through-fault damage than improvements toward the ends of feeders. Fuse-saving schemes offer a reduction in transformer through-fault damage compared to trip-saving schemes but can impact selectivity and power quality for more customers when multiple reclosers are used in series. Sequence coordination eliminates the problems associated with unnecessary upstream recloser operation while further reducing transformer damage. In difficult coordination situations, especially when fault current magnitude alone cannot be used to establish selectivity, WPS systems can greatly reduce the impact of transformer through-fault damage.

When determining through-fault damage for any of the reclosing scheme enhancements discussed, the entire reclosing sequence must be considered. When compared to a three-trip trip-saving scheme, a reduction in operating time for one of the three trips can reduce transformer through-fault damage by 30 to 40 percent, but a greater reduction of transformer damage can be achieved by using more fast curve trips, limiting delay curve trips to one, and canceling reclose attempts by locating faults with WPS systems.

VI. REFERENCES

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VII. BIOGRAPHIES

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